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Chapter 10 - Need for the Proposed Rhinelander Project and the System Alternatives

Electric Deficiencies – Load, Reliability Stability

This chapter describes the transmission system in the Rhinelander area, the current problems and expected growth that might explain the need for improvements. It includes a discussion of feasibility, economics and environmental impacts of non-transmission alternatives that could meet any increased need. In addition, this chapter includes a discussion of the engineering and environmental aspects of transmission solutions that are alternatives to the proposed project.

The analysis in this chapter examines various aspects of the need for and alternatives to the proposed line, one at a time. In some cases, the analysis and discussion bearing on a single aspect of need or the alternatives to the line may arrive at a particular observation. These singular observations should not be taken out of context. The complexity, size, and scope of the Arrowhead-Weston Transmission Project project require a balanced consideration of all the important factors.

Transmission system reliability

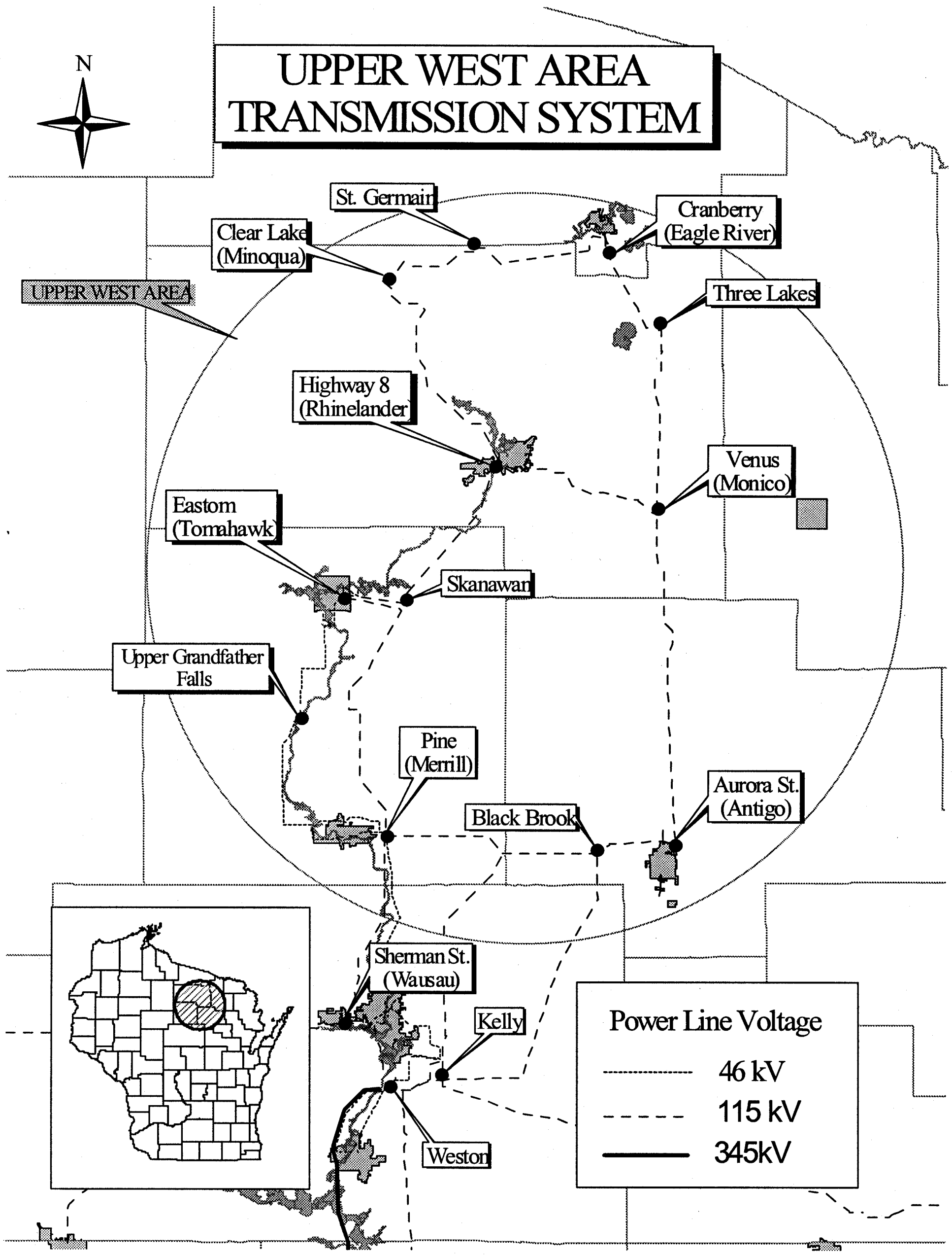
The proposed Tripoli-Rhinelander project is intended to alleviate significant problems in the existing WPSC transmission system serving north-central Wisconsin. Figure 10-1 shows the 115 kV transmission system in this area. WPSC refers to the part of its system north of Wausau as its "Upper West" area.

This part of the power system is an electrical cul-de-sac, with all significant connections to the rest of the Wisconsin power system concentrated in the Wausau area. There is only a small amount of generation in this area; essentially all power must be supplied from the Weston Power Plant or from Wausau-area transmission connections. Because of this configuration, the pattern of power flows into this area is primarily determined by customer demand within the Upper

West area. Unlike the case of the state as a whole, the pattern of power flow is affected very little by the particular pattern of generation dispatch in the state and region.

As a consequence, the analysis of the transmission needs in this area is much more straightforward than for the state as a whole. There is no need to debate the required transfer capability, for example.

Figure 10-1 Existing Upper West Area Transmission System



For this analysis, it is assumed that there is an adequate power supply outside the area and the system simply must be able to deliver all power required by electricity consumers.

Analysis of the power system in this area indicates that, at present levels of demand growth, some transmission lines may be at risk of overloading in the near future. The most significant concern in this area, however, as is typical of long transmission systems with generation or other significant power sources at only one end, is low voltage and the threat of voltage collapse.

These voltage problems are so severe that WPSC believes present electricity demand is close to the maximum level that can be served reliably. To ensure adequate system performance beginning this past summer, WPSC installed several Distributed Superconducting Magnetic Energy Storage (D-SMES) devices in the Upper West area. These devices can rapidly respond to system problems, providing voltage control and power to stabilize the grid. As electricity demand continues to grow, however, WPSC forecasts that the system may again be in a precarious position by 2003. Accordingly, some increase in electric generation or transmission capacity, or a decrease in electric demand, must be accomplished by 2003 to minimize the risk of a severe outage in the Upper West area.

From 2003 through 2010, the applicants predict that peak Upper West area electricity demand will grow by approximately 40 MW.[246]

Population and employment growth translates into electricity use increases and problems

The Tripoli-Rhinelander transmission project is being proposed partly because of expected growth in the use of electricity in northern Wisconsin as well as moderate to strong historical growth during the 1990s. Increases in electricity use are related to increases in population, employment, and increases in use per customer (residential, commercial, or industrial). When customer electricity demands increase beyond a certain amount, the existing transmission system cannot maintain adequate voltage or avoid facility overloads during contingency conditions. Consequently, customers could have low voltage or service interruptions (controlled, rolling blackouts). If a service interruption occurs, it can last for minutes or hours.

Table 10-1 shows historical population and employment statistics covering 1990 to 1999 for the counties in the Tripoli-Rhinelander transmission project area, the EWU, and Wisconsin. The table indicates that the project area's population has been growing at about the same 0.8 to 0.9 percent annual rates as that in the EWU area and in Wisconsin. The table indicates that the project area's non-farm employment has been growing at a much stronger rate, 3.2 percent annually, than that in the EWU area or in Wisconsin, which is around 2.2 percent annually. Vilas and Oneida Counties have experienced the strongest of the non-farm employment growth in the four-county area.

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[246] Page 53 Arrowhead to Weston Transmission Project application, Volume I, November 1999. This 40 MW estimate does not include the effects of the Crandon mine discussed in a later section.

Table 10-1 Economic trends around the Upper West area

Population (DOA)			
	1990	**1999**	**Annual Percent Change**
Langlade	19,505	20,622	0.62%
Lincoln	26,993	28,999	0.80%
Oneida	31,679	34,840	1.06%
Vilas	17,707	19,594	1.13%
Upper West Area	95,884	104,055	0.91%
EWU	4,075,888	4,405,050	0.87%
WIS	4,891,769	5,274,827	0.84%
Non-farm Employment (Wis. 4th Quarter UC system)			
	1990	**1998**	**Annual Percent Change**
Langlade	6,776	7,763	1.71%
Lincoln	10,496	12,560	2.27%
Oneida	12,955	17,172	3.59%
Vilas	4,675	7,270	5.67%
Upper West Area	34,902	44,765	3.16%
EWU	1,929,922	2,292,405	2.17%
WIS	2,248,980	2,693,748	2.28%

Sources: Bureau of Labor Market Information, Wisconsin Department of Workforce Development, Fourth Quarter Unemployment Compensation reports; and Wisconsin Department of Administration.

The base-case peak demand forecast for this area filed by WPSC in AP-8 assumed that peak demand would continue to grow at about 2.5 percent per year, consistent with historical experience. The forecast in the CPCN application is consistent with the AP-8 base forecast.[247] This forecast shows peak Upper West area demand increasing from about 210 MW today to about 265 MW in 2010. For the period 2002 to 2010, the projected increase in peak electric demand in the Upper West area is 40 MW. This value is used in subsequent analytic sections. Table 10-2 presents historical and projected peak electric demand for the Upper West area. Demand projections in Table 10-2 appear reasonable in light of historical experience and current population and employment trends.

[247] For comparison, the projected AP-8 statewide demand forecast growth rate was 2.0 percent per year. For the WPSC service territory as a whole, the Commission-approved projected AP-8 forecast growth rate for electric demand was 2.1 percent per year.

Table 10-2 Peak electrical demand in the Tripoli-Rhinelander area

Year	Electric Demand (MW)
1998	210
2002	225
2007	255
2010	265

Potential new demand growth associated with the Crandon Mine

The load forecast increase of 40 MW included in the application is based on broad trends and recent historical experience, and does not account for significant step changes in load associated with siting of new mining facilities in the area. Nicolet Minerals has, for several years, been working to obtain needed approvals to construct facilities and begin mining a zinc/copper deposit at a site in Forest County to be known as the Crandon Mine. WPSC would be required to provide electrical service to the mine, which has an estimated demand of 20.5 MW. WPSC has filed a separate CPCN application for a transmission line to serve the Crandon Mine. This would be a significant demand addition that would have to be factored into any plans to reliably serve load in the Upper West area. Authorization for construction and operation of the mine would increase the need for reinforcement of the Upper West area power system. Even if the mine does not proceed, however, system improvements or the cessation of future load growth will be required to alleviate the risk of a severe outage in this area. As a consequence, the potential Crandon Mine load can be viewed as hastening the need for improvements, rather than creating the need for improvements.

Non-Transmission Solutions

No-build alternative and reliance on competitive wholesale market

Commission staff's analysis indicates that doing nothing is not a viable alternative. Using the existing transmission system, as is, will not provide adequate or reliable service by the end of 2007. People in the four-county project area (Langlade, Lincoln, Oneida, and Vilas) will be at an increasing risk of service interruptions. The longer system improvements are delayed, the greater the risk of service outages as the growing customer demand for electricity taxes the existing transmission system. Without transmission improvements, the number and duration of service outages would likely increase.

Similarly, reliance on competitive wholesale markets appears unlikely to provide the requisite electric generation in the specific four-county area. While it is possible that a merchant power plant could locate in the four-county area, obviating the need for some or all of the transmission improvements, this probability cannot be predicted.[248] While it is true that the use of merchant power plants on a statewide basis may obviate some statewide needs for transmission improvements, the issue becomes more complicated when a specific area of the state, like the four-county area, must be targeted for new generation.

Utilities are required by law to provide reliable service. As sometimes happens, however, customers may experience service interruptions when storms knock down power lines. This type of interruption is unavoidable because it is impossible to build power lines so that they are capable of withstanding the forces of nature. In contrast, increases in customer use of electricity are predictable. If additional energy conservation cannot offset these increases, utilities must add facilities to the existing transmission system to prevent it from being overburdened and causing service interruptions to customers.

While some may suggest that loss of service from time to time would be tolerable, recent experience says otherwise. Between 1997 and 1999 the possibility of service interruptions loomed in eastern Wisconsin during summer months because of generation outages in eastern Wisconsin and northern Illinois, continuing load growth in a booming statewide economy, and a congested transmission system. Customers of every type and size became concerned about service reliability because of service interruptions. Residential, commercial, and industrial customers in eastern Wisconsin expressed their concerns to the Commission and the legislature that their business, health, safety, and welfare would be at risk without electricity. This would undoubtedly be the case in the Upper West area as well.

Load reduction alternatives

Energy efficiency

For a general discussion of energy efficiency measures, including utility-sponsored DSM measures, how energy efficiency can defer or reduce the need for power lines, its environmental benefits, the Commission's legal requirements concerning DSM, and changes occurring in the regulation of DSM, see Chapter 4.

What analysis of DSM have the applicants done?

The applicants originally announced their intent to build the proposed power lines in April 1999. On June 17, 1999, Commission staff informed the applicants of a requirement to provide DSM analysis in their application. The applicants were instructed to "use proxy calculations to determine if conservation alternatives might be cost-effective." The original filing, on November 10, 1999, contained only one paragraph (p. 58) related to the DSM alternative to

[248] Back in the 1994 to 1995 time frame, WPSC and Rhinelander Paper Company proposed building a small 135 MW coal cogeneration unit called the Rhinelander Energy Center. This unit would have assisted the area's local transmission needs and perhaps offset some of the current needs for transmission improvements. However, despite winning in a competitive bidding process, the Rhinelander Energy Center project eventually was withdrawn by WPSC and Rhinelander Paper Company. Whether such a proposal may occur again in the near future cannot be predicted. To date, no such plans by a utility or merchant power plant developer have been filed with the Commission.

Tripoli-Rhinelander. The applicants rejected DSM as an alternative to the Tripoli-Rhinelander proposed project because:

> The implementation of conservation practices or the installation of distributed generation, possibly utilizing renewable resources, are generally considered Targeted Area Planning (TAP) alternatives to the construction of new transmission lines. Projects proposed in Advance Plan 8 to address the developing transmission system deficiencies in the Upper West area were screened for the potential use of TAP solutions. The screening process conducted in Advance Plan 8 determined that the load growth characteristics of the region precluded the implementation of a TAP solution. Additional discussion pertaining to TAP in the Upper West area, or other projects proposed in Advance Plan 8, can be found in the AP-8 Technical Support Document D23t-Targeted Area Planning Screening. (Application, p. 58.)

No economic analysis of the cost-effectiveness of energy efficiency was included in the original application. Commission staff identified this lack of analysis to the applicants on November 23, 1999. Subsequently, on December 7, 1999, the Commission was provided with a supplemental analysis of the cost-effectiveness of conservation. This analysis is included in Appendix C.

Applicants' feasibility analysis of energy efficiency (Tripoli-Rhinelander)

The applicants' discussion of the feasibility of DSM to substitute for the Tripoli-Rhinelander power line in their original filing claimed that the TAP screening process conducted in AP-8 determined that the load growth characteristics of the Rhinelander region precluded the implementation of a TAP solution. AP-8 document D23t, page WPS-4, screens the Rhinelander area from further TAP analysis based on load growth due to the possibility of "bulk load additions." Bulk load was defined as "any sudden or contingent appearance of a load or generator greater than 30 MW." Examples of such bulk additions are a large industrial development, such as the Crandon Mine, or a residential subdivision. WPSC did not specify any particular bulk load addition possibilities in that document.

The applicants' supplemental analysis, shown in Appendix C, eliminates this fatal flaw criterion of "bulk load." Instead, it concludes that the area is amenable to further TAP analysis. The applicants continue to note, however, in their discussion of "Need Location" that, "the possibility of a bulk load addition may be a mitigating factor for any energy efficiency and renewable opportunities from a TAP screening perspective."

Unlike the Arrowhead-Weston line, the proposed Tripoli-Rhinelander line does lend itself to TAP analysis. The applicants discuss the applicability of alternatives such as targeted DSM by reviewing the TAP screening criteria developed by the consensus TAP Collaborative process. In their supplemental analysis, the applicants conclude that the need in the Rhinelander area is of a type that is worthy of further TAP analysis.

The applicants performed this analysis by examining the potential for DSM to defer the Tripoli-Rhinelander project. End-uses considered for efficiency in their analysis were limited to residential water heating, air conditioning, refrigerators and dehumidifiers, and commercial-industrial cooling. After increasing the efficiency of these end-uses, they concluded that, at maximum, there is potential for reducing demand by between 14 MW and 16 MW. This, they say, is short of the 41 MW needed through 2010. This analysis largely ignores the potential for load management, load control, and interruptible and curtailable loads to address the capacity need. Only residential electric water heater timers are mentioned as a possible load management option. It also ignores the potential for fuel switching options to contribute to demand reduction.

The applicants also concluded that, because DSM cannot meet the entire need for capacity, "conservation is not a viable option for the Tripoli-Rhinelander transmission line." This "all-or-nothing" approach does not consider the extent that energy efficiency may be able to contribute to a package that includes some transmission and new generation to meet any need for additional capacity.

Applicants' supplemental economic analysis of DSM (Tripoli-Rhinelander)

The applicants' supplemental economic analysis of DSM as an alternative to Tripoli-Rhinelander, as shown in Appendix C, has a number of significant problems if used as a basis for Commission consideration of the cost-effectiveness of energy efficiency.

The applicants calculated what they believe to be the cost of DSM. This cost was expressed as a cost per MW. The number was calculated by dividing WPSC's 1998 total electric DSM spending of $5,103,070 by the 4.11 MW claimed to have been captured though WPSC's DSM programming. The result was $1,241,623 per MW. That cost per MW was then multiplied by the applicants' claimed need of 41 MW through 2010. After accounting for present value, the result was $25,277,316 for 41 MW of demand reduction. The applicants implied that this cost should be compared to the cost of the Tripoli-Rhinelander power line.

The first problem with this analysis is that the dollars used for 1998 DSM spending are not representative of the cost of energy efficiency. In 1998, WPSC contracted with the DOA to deliver most of its DSM programming. WPSC transferred roughly $8 million to the DOA for 1998 and received credit for roughly 70 percent of its 1998 electric energy savings goal. The costs cited by the applicants represent the costs for programs that WPSC chose to retain in-house in 1998. These programs are not representative of best practice, cost-effective energy efficiency programs. The cited cost for these programs, $5,103,070, also includes $3,589,020 (70 percent) in "level 4 costs." Level 4 costs represent general and administrative dollars not attributable to any specific program, or even to the programs for any specific customer sector.

The second problem with the applicants' analysis is that the calculation of cost per MW includes the costs of conservation programs that were not primarily designed to capture demand savings alone. Conservation programs generally are designed to save energy (kWh) cost-effectively. Load management programs and conservation programs targeted at peak energy use can capture demand savings at a lower cost per MW.

The third and most significant problem with the applicants' economic analysis is that the DSM was not given economic credit for avoided energy costs. To the extent that DSM saves energy as well as demand, it must be credited with the costs of the energy generation that are avoided. If most utility conservation programs are cost-effective due to avoided energy costs (even without avoiding the costs of a major transmission line), then the net cost of those programs is negative. By comparison, the applicants attribute no cost to the power and energy that would have to be generated and transmitted over the proposed power lines. Presumably, at times of system peak, these costs would be significant.

Intervenor's analysis of energy efficiency

WED, an intervenor with full-party status in this docket, had indicated an intention to address the issue of the potential for an energy efficiency alternative to the proposed power lines. The Commission staff will work with intervenors and the applicants to provide a hearing record that is adequate for the Commission to evaluate energy efficiency as an alternative to the transmission projects. Commission staff will review any analysis performed by WED and other parties during the hearings in this docket.

Real-time pricing

Another alternative to the construction of transmission facilities serving the Upper West area is to implement RTP for large industrial and commercial customers. Basically, RTP, a form of peak load pricing, refers to the practice of charging for electricity at a tariff rate corresponding to a particular hour's marginal cost of production. For instance, if the marginal cost of producing electricity at 1 p.m. is $0.09 kWh, then the customer pays $0.09 kWh. At 1 a.m., when the marginal cost of producing electricity is $0.02 kWh, the customer pays $0.02 kWh. This is in contrast to the present rate situation in Wisconsin in which numerous industrial and commercial customers pay a flat $0.0386 and $0.0587 kWh, respectively, regardless of the hour that the electricity is used.[249] By implementing real-time pricing, industrial and commercial customers face the real cost of producing electricity.[250] This form of price signaling provides a strong incentive for a customer to reduce demand when hourly electricity prices are high, and conversely, increase demand when hourly electricity prices are low. Reducing demand during peak periods of electricity use represents a load reduction that can directly translate into reduced needs for new generation and transmission facilities.

Chapter 4 covered RTP as a load reduction alternative and found that up to 258 MW of load reduction could be available from a full-scale implementation of RTP in Wisconsin. In order to avoid building the Tripoli-Rhinelander transmission line, approximately 40 MW of available capacity would need to be located in the Upper West area. This value comes from the amount of load growth expected in the area between 2002 and 2010 that would need to be served, at a minimum, by either a transmission or generation option.

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[249] These values are statewide averages and are from the US DOE EIA publication, Electric Sales and Revenue 1998. Some industrial and commercial customers do face time-of-day rates, which are a form of peak load pricing.

[250] There are several tariff methods that can be used to implement RTP. Such methods are not discussed here. This is because it is more important in this EIS to convey the overall concept rather than which method will produce the optimal load reduction or will or will not recover fixed and stranded costs.

On its face, the scale of statewide load reduction from RTP appears to be able to offset the 40 MW deficit in the Upper West area. However, the locations of the load reductions from RTP would be spread throughout the state and for electrical engineering purposes would be unlikely to offset this particular locale's need. Consequently, statewide RTP is not a viable alternative to offset the transmission requirements in the Upper West area.

Furthermore, RTP implemented just in the area around Tripoli-Rhinelander would not be a viable alternative. This is because load in the area is around 250 MW. As described in Chapter 4, no more than 20 percent of such local load would likely participate in an RTP program. The average load reduction achieved by an RTP program appears to be around 12 percent. Thus, the implementation of RTP, alone, in the Tripoli-Rhinelander area would likely reduce load by 6 MW, an insufficient amount to offset the entire need for local area transmission improvements. RTP could, however, be implemented as one option in a "package" of options along with transmission upgrades, new generation, and energy efficiency to meet the growing need in the future.

Conventional generation alternatives

New generation can be a substitute for the construction of new transmission facilities, although more often than not, generation and transmission facilities are complements to one another. In order to avoid building the Tripoli-Rhinelander transmission line, 40 MW of available electric generating capacity would need to be located in the Upper West area.[251] This value comes from the amount of peak load growth expected in the area between 2002 and 2010 that would need to be served at a minimum by either a transmission or generation option. In the following analysis, generation is assumed to replace transmission import capability one-for-one.[252]

Presently, around the country there is active industry development of both combustion turbines and combined-cycle units. Displacing a line equivalent to 40 MW in peak generating capacity ordinarily requires smaller generation projects with lower fixed costs, such as a natural gas-fired combustion turbine. In the following analysis, 40 MW of peaking capacity from a combustion turbine is used as a potential substitute for the proposed transmission facilities in the Upper West area. In AP-8 a small-scale single-unit combustion turbine had an ordinary construction cost of $409/kW in 1999 dollars.[253] Total cost for the construction of 40 MW of combustion turbine capacity would be $16.36 million. The annual impact on rates in 1999 dollars of the

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[251] Page D-29, Arrowhead to Weston Transmission Line Project application, Volume II, November 10, 1999.

[252] This was not the case for the Arrowhead-Weston Line, because a multi-unit analysis was performed. The use of the one-for-one approach here is most favorable to the generation option because in actual operation one particular combustion turbine can be either on- or off-line. In a multi-unit analysis, a particular unit may be on- or off-line when other units are running. This aspect lends itself to an equivalence analysis such as that used for the Arrowhead-Weston line, which required 6 percent more generation than transmission line import capability.

[253] The actual size of the AP-8 unit is 75 MW; 40 MW is assumed here.

capital cost component would be $1.19 million. This is based on a levelized annual capital charge of $29.78 per kW. This value is calculated using a conventional revenue requirement model. Parameters used in the revenue requirement model were specifically described earlier in Chapter 4, but generally are either from AP-8 or those associated with the actual capital structure of WPSC.

With respect to the costs of the Tripoli-Rhinelander transmission line, the construction cost for the transmission line is estimated at $20 million.[254] The annual impact on rates in 1999 dollars of the line's capital cost would be $1.74 million. These values were similarly calculated using a conventional revenue requirement model.

In order to compare generation and transmission alternatives for cost-effectiveness, the annual impact on rates must be analyzed. Table 10-3 presents the annual ratepayer impact of using either combustion turbine or wind generation versus transmission to meet the Upper West area's electricity needs. In order to derive the following analysis, certain additional assumptions have been made:

- The marginal running (energy) cost of a small-scale combustion-turbine unit is $36.30/MWh based on the recent AP-8's estimate of a full load heat rate of 12,254 BTU/kWh, $2.86/MBTU for natural gas, and $1.25/MWh for variable O&M for a combustion turbine.[255]
- The Midwest ISO is in place, and energy purchases are from Midwest ISO members. This means that the comparative transmission rate in the cost analysis drops to zero since each of the options in Table 10-3 would face the same tariff. Under the Midwest ISO, the transmission tariff for a purchase is based on the location of the load being served.
- The combustion turbine is used 850 hours per year with more use in the summer than in the winter; this represents a 9 percent capacity factor and is in line with industry practice.
- Purchased power prices in the first analytical cost method replicate the actual system power purchase practices of the state's five largest investor owned electric utilities in 1999. According to FERC Form 1 Account 555 data, the average energy purchase price in Wisconsin was $24.11 per MWh in 1999. In terms of capacity charges, it is assumed that 40 MW of combustion turbine capacity provide the firm supply backup. This requires a proxy capacity charge of $1.19 million.
- Purchased power prices in the second analytical cost method are assumed to follow the market pattern displayed from June 1998 to May 1999. According to

[254] This is a Commission engineering staff cost estimate.

[255] The actual calculation is as follows: [(12,254*$2.86)/1000] + [$1.25] = $36.30/MWh.

Bloomberg, the median day-ahead spot-market price for firm daily peak energy in MAIN was $32.50/MWh, June 1 to September 15, 1998; $21.50/MWh, September 16, 1998 to December 15, 1998; $19.89/MWh, December 16, 1998 to March 31, 1999; and $25.59/MWh, April to May 1999.[256] In addition to these energy prices, a separate demand charge or proxy capacity charge equivalent to 28.3 percent of the total energy charge is assessed. Chapter 4 provides the rationale for this 28.3 percent estimate.

- The generation-only analyses would still require certain other transmission line upgrades, specifically a Wausau 46 kV conversion which has been estimated to cost $1.5 million. The annual impact on rates in 1999 dollars of this conversion is estimated at $0.12 million.
- The transmission project gets a $1.19 million credit for reducing energy losses on the system. This credit is based on a 7.5 MW savings for 7910 hours (the number of hours when the generation is not running) at $20/MWh. This credit reflects the net comparative energy savings of the transmission line improvements over the electric generation equivalent.

[256] Power prices are for firm on-peak power with liquidated damages.

Table 10-3 Comparison of conventional generation and transmission project costs

Comparison of Generation and Transmission Project Costs				**Method 1**	**Method 2**
Reliability Perspective				**Tripoli**	**Tripoli**
1999 Dollars				**Rhinelander**	**Rhinelander**
				Project	**Project**
		AP-8 CT	**AP-8 Wind**	**Avg. Purchased**	**Bloomberg**
	Item	**Generation**	**Generation**	**Power Prices**	**Power Prices**
Capital cost $/kW		$409	$1,112		
Capacity equivalence MWs		40	80	40	40
Total construction cost (millions)		$16.4	$89.0	$20.0	$20.0
Levelized annual charge $/kW		$29.78	$90.30	NM	NM
Yearly capital cost (millions)	A	$1.19	$7.22	$1.74	$1.74
Capacity charge (millions)	B	$0.00	$0.00	$1.19	$0.27
Fixed O&M (millions)	C	$0.10	$0.00	$0.05	$0.05
Summer energy price $/MWh		$36.30	$9.76	$24.11	$32.50
Hours of summer duty		475	475	475	475
Summer energy cost @ 40 MW (millions)	D	$0.69	$0.19	$0.46	$0.62
Fall energy price $/MWh		$36.30	$9.76	$24.11	$21.50
Hours of fall duty		150	150	150	150
Fall energy cost @ 40 MW (millions)	E	$0.22	$0.06	$0.14	$0.13
Winter energy price $/MWh		$36.30	$9.76	$24.11	$19.89
Hours of winter duty		75	75	75	75
Winter energy cost @ 40 MW (millions)	F	$0.11	$0.03	$0.07	$0.06
Spring energy price $/MWh		$36.30	$9.76	$24.11	$25.59
Hours of spring duty		150	150	150	150
Spring energy cost @ 40 MW (millions)	G	$0.22	$0.06	$0.14	$0.15
1999 annual capacity & energy cost (millions)	H	$2.53	$7.56	$3.80	$3.02
+ Wausau 46 kV conversion (millions)	I	$0.12	$0.12		
Federal tax credit for wind generation (millions)	J		$0.51		
Energy credit for reducing losses on system	K			$1.19	$1.19
Total costs (millions)	L	$2.65	$7.17	$2.61	$1.83
H=A+B…G					
L=H+I-J-K					

The analysis in Table 10-3 shows that the annual operation of the combustion turbine unit would cost $2.65 million; importing power using the transmission grid would cost between $1.83 and $2.61 million. This represents a modest cost savings in favor of the line. The results above indicate that the Tripoli-Rhinelander project could be more cost-effective than building new combustion turbine generation. However, the largest absolute dollar value difference is less than $1 million. This small difference suggests that caution should be applied in any interpretation of the estimates above. Due to the small absolute differences, the combustion turbine and line alternatives may be quite competitive with one another. This conclusion is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs. The next section discusses the Table 10-3 results for the use of wind generation as an alternative.

Wind generation alternatives

The prior section compared the annual ratepayer cost impact of combustion turbine technology versus construction of the Tripoli-Rhinelander transmission line. This section continues the comparison using a promising renewable energy resource for electricity generation, wind. In AP-8 the cheapest wind generation project had an ordinary construction cost of $1,112 per kW in 1999 dollars. In this section, wind generation is assumed to have a capacity contribution factor of 50 percent. This means that 80 MW of wind generation must be used on average to supply 40 MW of electrical generation, the amount that would be imported over the Tripoli-Rhinelander new line.[257] Total cost for the construction of 80 MW of wind generation would be $7.22 million, based on a levelized annual capital charge of $90.30 per kW. However, there is a $15.00 per MWh tax credit for wind generation under federal tax law.

In order to compare wind generation with the Tripoli-Rhinelander transmission alternative for cost effectiveness, the annual impact on rates must be analyzed. Table 10-3 above presents the annual ratepayer impact in 1999 dollars of using either 80 MW of wind generation or 40 MW of transmission line energy imports to meet the Upper West area's reliability-associated electricity needs. Similar to the treatment for the combustion turbine, certain assumptions are needed. The marginal running or energy cost of wind generation is assumed to equal its AP-8 variable O&M value of $9.76 per MWh in 1999 dollars.

The analysis in Table 10-3 shows that the annual operation of 80 MW of wind generation would cost $7.17 million; importing power using the transmission grid would cost between $1.83 and $2.61 million. This represents a solid cost savings in favor of the Tripoli-Rhinelander line. The results above indicate that the Tripoli-Rhinelander project is more cost-effective than wind generation. This conclusion is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs.

[257] The 50 percent value is an assumption in strong favor of wind generation, as values between 7 and 30 percent have been debated in prior Advance Plans.

Distributed generation

The prior two sections compared the annual ratepayer cost impact of combustion turbine and wind technology versus construction of the Tripoli-Rhinelander transmission line. This section makes a similar comparison using two distributed generation resources: fuel cells and micro turbines. A complete description of these distributed generation technologies can be found in Chapter 4. In the analysis that follows, the same costs are utilized for the conventional combustion turbine as developed earlier in this chapter.

As indicated in Chapter 4, Commission engineering staff has developed the following cost estimates with respect to micro turbines. The ordinary construction cost is about $900 per kW in 1999 dollars when multiple units are constructed. The levelized annual capital charge for the micro turbines is $77.47 per kW, which has been determined by a conventional revenue requirements analysis using the same expected life span as that of a conventional combustion turbine. For the marginal energy cost of micro turbines, the $21.95 per MWh estimate is based on an expected full load heat rate of 7,500 BTU/kWh, $2.86 MBTU for natural gas fuel, and $0.50/MWh for variable O&M.[258] Fixed O&M for the micro turbine units is also estimated at $5.00 per kW in 1999 dollars.

For fuel cells, the DOE EIA has developed cost estimates.[259] The ordinary construction cost is about $2,163 per kW in 1999 dollars when multiple units are constructed. The levelized annual capital charge for the fuel cells is $185.94 per kW, which has been determined by a conventional revenue requirements analysis using the same expected life span as that of a combustion turbine. The estimated marginal energy cost of fuel cells of $19.21 per MWh is based on an expected full load heat rate of 6,000 BTU/kWh, $2.86/MBTU for natural gas fuel, and $2.05/MWh for variable O&M.[260] Annual fixed O&M for the fuel cells is also estimated at $14.74 per kW in 1999 dollars.

In Table 10-4, which compares a conventional combustion turbine to micro turbines and fuel cells, certain other assumptions have been made. First, all three technologies are expected to operate 850 hours per year; this represents about a 10 percent capacity factor, which is in line with industry practice for peaking duty. Each of the technologies also uses 40 MW of capacity to actually generate electricity for reliability purposes. Due to the scale of the project no capacity is held in standby reserve.

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[258] The actual calculation is [(7,500*2.86)/1000] +[$0.50] = $21.95 MWh in 1999 dollars.

[259] Annual Energy Outlook 2000, Table 37, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies, US DOE EIA. Available at http://www.eia.doe.gov/oiaf/aeo/assumption/tbl37.html.

[260] The actual calculation is [(6,000*2.86)/1000] +[$2.05] = $19.21 MWh in 1999 dollars.

Table 10-4 Comparison of combustion turbine, micro turbine, and fuel cell technology costs

	AP-8 Single-Unit CT	Micro Turbine	Fuel Cell
Fixed Costs			
Capital cost $/kW	$409.00	$900.00	$2,163.00
Levelized annual charge $/kW	$29.78	$77.47	$185.94
Fixed O&M $/kW	$2.50	$5.00	$14.74
Marginal Costs			
Variable O&M $/MWh	$1.25	$0.50	$2.05
Full load heat Rate	$12,254.00	$7,500.00	$6,000.00
Fuel cost	$2.86	$2.86	$2.86
Energy cost $/MWh	$36.30	$21.95	$19.21
Total All-In Costs $ Millions			
850 Hours of peak generation	$2.53	$4.05	$8.68
+ Wausau 46 kV conversion	.12	.12	.12
Total costs (millions)	**2.65**	**4.17**	**8.80**

Values in 1999 dollars.

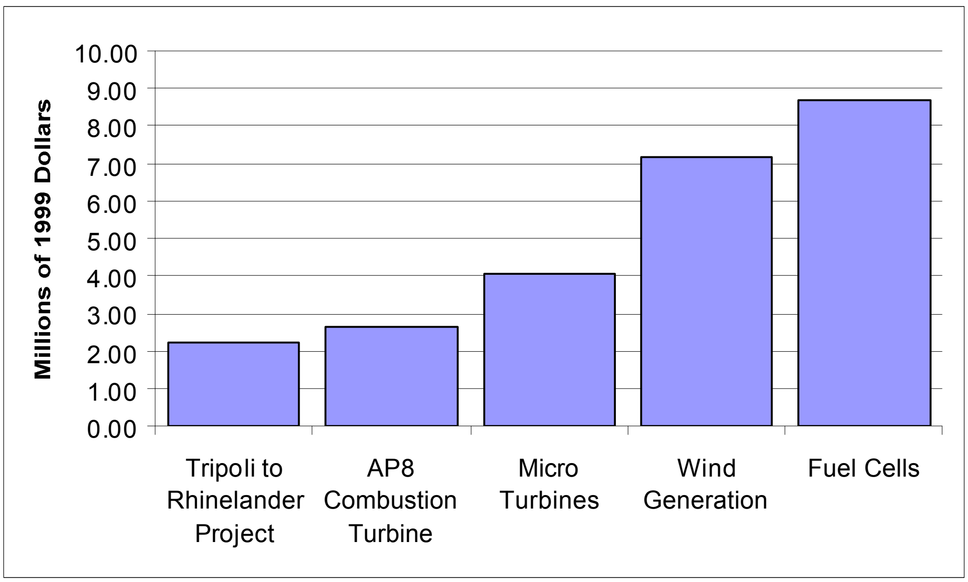
The analysis in Table 10-4 shows that the annual operation of 40 MW of combustion turbines costs $2.5 million. In comparison, operation of micro turbines and fuel cells would cost between $4 and $9 million. In the case of micro turbines, the estimated cost is around $1.5 million more than the conventional combustion turbine. Fuel cells are substantially more expensive than combustion turbines or micro turbines. As can be seen in Table 10-4, both micro turbines and fuel cells have lower marginal costs of operation than a conventional combustion turbine. However, their substantially higher fixed capital costs create an all-in cost that is larger than that for the combustion turbine. Consequently, the use of 40 MW of micro turbines or fuel cells in place of combustion turbines simply for reliability purposes may not be a cost-effective alternative. This conclusion is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs.

There are two important caveats to this conclusion.

First, the analysis in Table 10-4 does not include the fact that distributed generation resources may have the potential benefit of displacing some of those ancillary services required to run the electricity network. These ancillary services include generation resources used for regulation and frequency response, spinning reserves, operating reserves, voltage support, and reactive power, as well as system control and dispatch. This means that distributed generation should receive a credit for avoiding the costs associated with the identified ancillary services. However, it is not possible to gauge the quantitative extent of this credit impact.

Second, while the results in this section indicate that micro turbines are somewhat more expensive than using a conventional combustion turbine, and by extension, somewhat more expensive than the Tripoli-Rhinelander transmission project, the absolute dollar value differences are approximately $1.6 to $2.3 million. This relatively small difference suggests that caution should be applied in any interpretation of the estimates above. Due to the small absolute differences, a micro turbine alternative may be competitive with either the combustion turbine or the Tripoli-Rhinelander project. The following figure displays the annual cost to customers of assorted alternatives to the construction of the Tripoli-Rhinelander transmission line project.

Figure 10-2 Comparison of annual cost to customers for generation alternatives



Rhinelander non-transmission alternative summary

The following comments summarize the above cost analyses of non-transmission alternatives to a Tripoli-Rhinelander transmission line:

- There is still some uncertainty about the level of energy efficiency available. A somewhat cursory analysis done by the applicants indicated that there was not enough energy efficiency to meet the anticipated need. Additional analyses of energy efficiency potential may be completed by an intervenor and presented in this case.
- Commission staff's analysis found that RTP could not meet all the need.
- Commission staff's analysis of generation options found that each costs more than the proposed transmission options. The combustion turbine option, however, is close enough in cost to warrant further investigation.

- Environmental costs and benefits were not factored into the cost analysis of any alternative.

An "all or nothing" approach ignores the fact that the capacity need could be met by a combination of some of the above elements. Each alone may not be able to meet the forecasted increase in need in the Upper West area through 2010, but a combination of smaller amounts of several options may be able to meet the need from both a cost and performance perspective. For example, if energy efficiency and RTP cost less than transmission options it might be possible to use some of those cost savings to make up any cost difference of generation options.

Due to recent changes in industry structure and laws governing regulatory oversight, there is no longer a mechanism that facilitates an integrated approach to using generation, transmission and energy efficiency alternatives.

Environmental effects of generation alternatives

The environmental impacts associated with constructing 40 MW or less of new generation could be substantial, depending on the generation technology used and the site selected for a plant. The technology options able to meet all or part of the 40 MW capacity include a small coal facility, a small combustion turbine, a biomass plant, wind generation, or distributed generation sources, such as micro turbines. There is a brief description of the potential environmental effects of these technologies below. A more detailed discussion can be found in Chapter 4.

Coal

Siting a coal facility would likely cause the greatest human and environmental impact among these generation options. Installation of a coal plant would require a substantial amount of land for the buildings, stockpiled coal, loading facilities and ash disposal. In addition, water use and thermal discharge impacts are much greater for coal plants than for CT or CC plants. Lastly, emissions from coal-fired generators generally contain greater amounts of SO_2, NO_x, CO_2, particulates, and mercury than other combustion technologies. An application filed by WPSC in 1994 for a coal facility to be located at the Rhinelander Paper Company was subsequently withdrawn.

Combustion turbine

Construction of one or two small natural gas-fired combustion turbines to meet peak energy demands would require less than 10 acres of land. The water requirements for NOx[261] control and other needs would be about 35 gallons per minute per unit and could potentially be supplied by a municipal water supply system. Demineralized water used for cleaning plant equipment would likely be brought in from off-site. Expected air emissions from a 25 MW gas-fired peaking plant would be at levels shown in the table below. Number 2 fuel oil is generally stored on site as a back-up fuel.

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[261] This assumes standard wet NOx burners.

Table 10-5 Potential emissions for a 25 MW combustion turbine

Pollutant	Emissions (lbs/hr) When Firing Natural Gas*	Emissions (lbs/hr) When Firing No. 2 Fuel Oil*
NOx	120.0	120.0
SO_2	0.2	170.5
CO	120.0	120.0
PM_{10}	33.8	33.8
VOC	84.0	84.0

* Values derived from analysis of a 25 MW gas fired combustion turbine at Manitowoc, WI.

Construction of the related facilities, including an interconnection to the electric transmission system and a pipeline for supply natural gas to the plant, could result in greater environmental impacts, depending on the location of the nearest electric and gas transmission system.

Micro turbines

- Installation of one or more micro turbines, small self-contained gas turbines with a limited capacity usually less than 300 kW per unit, at commercial or industrial sites with high energy demands, could also be a viable alternative with minimal environmental impacts. There are several engineering and cost issues associated with this technology that have to be addressed (see Chapter 4) before micro turbines can be used on a broad scale basis. However, one or more turbines could be used to meet part of the 40 MW need.

Renewable resources

Although suitable wind resources may not be available in the immediate Rhinelander area, increments of other renewable resource options, such as biomass (whole-tree) or waste to energy (WTE) could possibly be implemented. The landscape, which is primarily forested, and the sawmills and paper mills present in the area, may provide opportunities to add generation capacity with fewer environmental impacts than conventional generation plants. Because of the higher costs and business risks associated with implementing these types of renewable generation capacity, it is likely that such a project would have to be developed by a non-utility generator. Some of the environmental impacts of biomass are described in Chapter 4.

Engineering Analysis of Alternative Transmission Line Solutions

Identification of transmission alternatives

Previous studies have investigated the Upper West area problems and potential transmission solutions. In particular, the AP-8 studies in 1998 identified several Upper West area transmission reinforcement projects (see AP-8 Technical Support Document D23r). WPSC has included additional alternatives in its application for the proposed project. The proposed

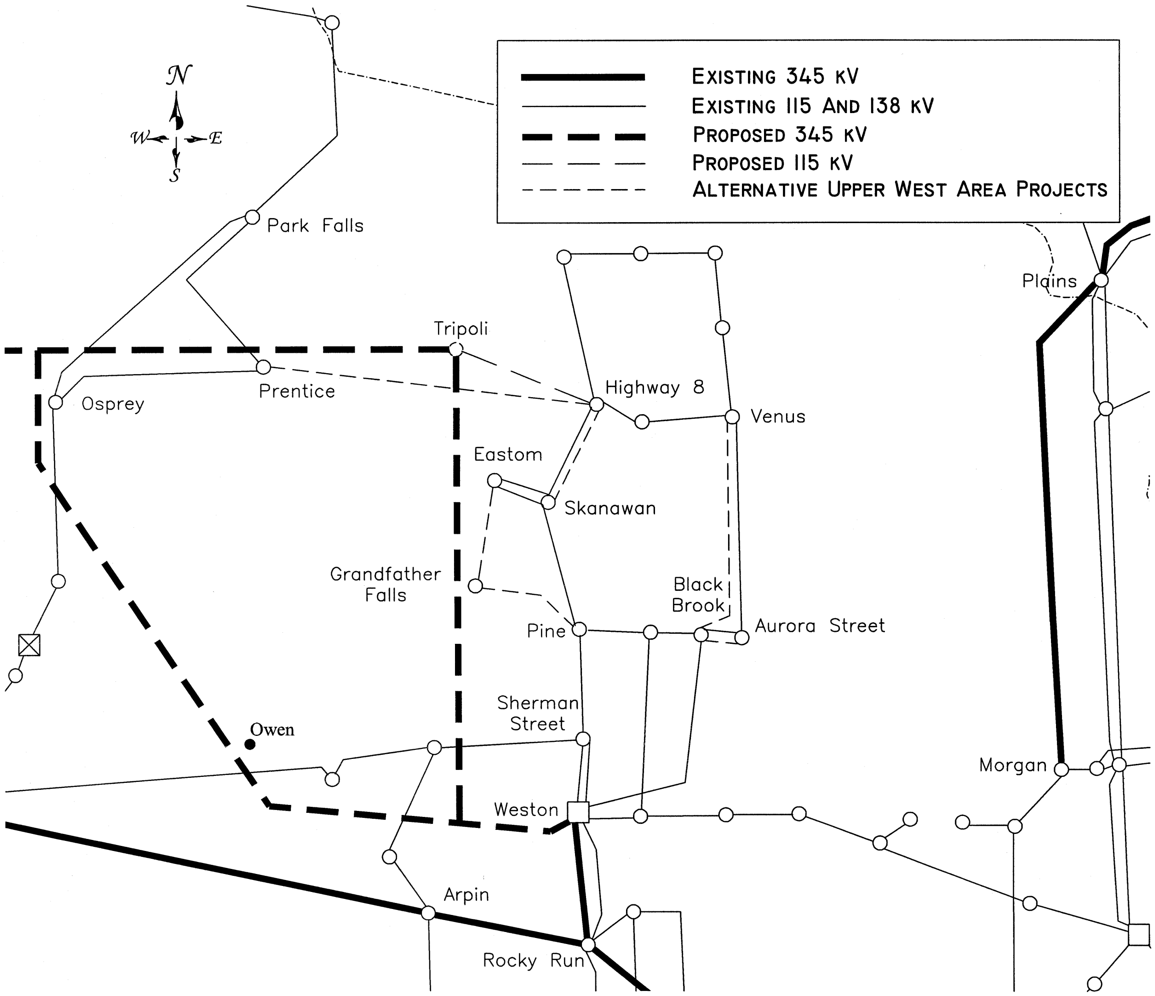
Tripoli-Rhinelander line and alternatives are described below. Figure 10-3 depicts new transmission lines that are included in these alternatives.

- The proposed Tripoli-Rhinelander 115 kV transmission line would connect the Highway 8 substation in Rhinelander to a new Tripoli substation on the Arrowhead-Weston 345 kV transmission line. This would require that the Arrowhead-Weston line follow the northern corridor between Exeland and Weston.
- The D-SMES alternative involves no construction of new permanent transmission lines. Rather, WPSC would install six additional D-SMES units through 2010, bringing the total number of installed units to twelve. These units, each of which is housed in a semi-trailer, would be installed at individual substations. In addition, approximately 60 miles of existing 115 kV line would have to be rebuilt during this period. Larger conductors would need to be installed to alleviate overloads that would otherwise occur. WPSC would build temporary transmission lines to maintain system reliability during reconstruction of these lines. These would be located between Aurora Street Substation and Venus Substation, and between Eastom Substation and Highway 8 Substation. The temporary lines would be removed once rebuilding of the permanent lines is complete.
- To implement the Parallel Circuit alternative, WPSC would replace the existing Black Brook-Aurora Street line with two 115 kV transmission lines running in parallel. Similarly, the existing Skanawan-Highway 8 line would be replaced with two parallel 115 kV lines. This would allow power to flow across these critical parts of the network even with one line out of service. One of the new Black Brook-Aurora Street lines would connect to Weston Substation, the other to Bunker Hill Substation. Similarly, one of the new Skanawan-Highway 8 lines would connect to Eastom Substation, the other to Pine Substation. The Black Brook and Skanawan switching stations could then be eliminated, as they would no longer be needed. In addition, the existing transmission line between Eastom Substation and Pine Substation via Grandfather Falls Substation, now operated at 46 kV, would be fully upgraded to 115 kV standards and would then be operated at 115 kV.
- The Black Brook-Venus 345 kV alternative involves building a new 345 kV line between those two substations. This line would be operated at 115 kV for the time being; however, it would be built so that it could be operated at 345 kV at some point in the future. While it is significantly more expensive to build a 345 kV line than a 115 kV line, building this line as a 345 kV line would facilitate construction, in the future, of a 345 kV line extending from the Weston Substation all the way to the Plains substation near the Wisconsin-Michigan border. Such a line would incorporate the existing Weston-Black Brook 115 kV line, almost all of which is already built to 345 kV standards. A Weston-Venus-Plains 345 kV line has been identified in previous transmission planning studies as a way to increase transfer capability into Wisconsin from generation located near Marquette, MI, and to provide support to the WPSC Upper West area (see AP-8 Technical Support Document D23r, for example).

- In a second Black Brook-Venus line alternative the line would only be constructed to 115 kV standards. This significantly reduces the size and cost of the line, relative to the Black Brook-Venus 345 kV alternative, but precludes eventual use as part of a 345 kV line.
- In the final alternative, a new Prentice-Rhinelander 115 kV line would follow a route similar to that of the proposed Tripoli-Rhinelander line. Rather than connecting to the 345 kV line at Tripoli, however, this line would continue west to connect to the existing 115 kV system at Prentice. In contrast to the proposed Tripoli-Rhinelander line, this arrangement would allow the Arrowhead-Weston line to follow a route along the generally shorter southern corridor, from Exeland to Owen to Weston. In this case, the Arrowhead-Weston 345 kV line would have a midpoint substation near Ladysmith rather than near Tripoli. Some new 115 kV line would also need to be constructed between this new substation and the existing Osprey substation. Depending on the route selected for the 345 kV line, the length of this new connection to Osprey could vary from twelve miles to a fraction of a mile.

These alternatives to the proposed Tripoli-Rhinelander line are included to facilitate evaluation of the applicants' proposal and provide an analysis of alternative sources of supply as required under Wis. Stat. §PSC 196.491(3)(d)(3).

Figure 10-3 Transmission system alternatives to the proposed Rhinelander Project



Performance and costs of proposed line and alternatives

Table 10-6 summarizes some of the performance and cost characteristics of the transmission alternatives. The information in this table is based on the application and follow-up data requests to the applicants.

Electrical performance

Each of the alternative plans was designed to include all upgrades necessary to ensure adequate performance through 2010. Nonetheless, there are discernable differences in the performance of the alternatives, which are important in predicting system reliability and required upgrades after 2010. In general, the more robust the performance of an alternative, the greater the range of fixes that can be expected to be effective in the future. This should tend to decrease the cost and environmental impact of future reinforcements that may be required.

Table 10-6 Performance and cost characteristics of the Tripoli-Rhinelander line and alternatives

	Alternative Name	Maximu Demand	Cost Impact				
			Construction	Other Facilities	345 kV Routing	Loss Credit	Total
1	Tripoli-Rhinelander 115 kV line	285 MW	$16,040,000	($4,372,000)	$13,112,000	($6,359,000)	$18,421,000
2	D-SMES plan	N/A	$16,181,000	$1,436,000	-	-	$17,617,000
3	Parallel Circuit Plan	267 MW	$19,733,000	$1,436,000	-	($2,121,000)	$19,048,000
4	Black Brook-Venus 345 kV line	268 MW	$24,996,000	$1,436,000	-	($2,374,000)	$24,058,000
5	Black Brook-Venus 115 kV line	278 MW	$13,752,000	$1,436,000	-	($1,865,000)	$13,323,000
6	Prentice-Rhinelander 115 kV line	272 MW	$21,593,000	($4,372,000)	-	($85,000)	$17,137,000

Parentheses indicate credit rather than cost. Totals may vary slightly from the sum of terms shown due to rounding.

One measure of robustness is presented in Table 10-6, in the column labeled "Maximum Demand." These values are the levels of Upper West area electricity demand at which the new transmission lines associated with each alternative would no longer provide satisfactory protection from voltage collapse. Some of the alternatives include several D-SMES devices, in addition to new transmission construction. The effect of these devices is not included in the results reported in Table 10-6; only the effect of new transmission line construction included in each alternative is shown. This provides a more fundamental measure of the robustness of each alternative, since devices such as the D-SMES units can always be installed to provide some improvement in performance.

Since the D-SMES alternative includes no new transmission lines, this analysis was not conducted for the D-SMES alternative, and no value is listed in the table. This should not be interpreted as indicating a lack of feasibility, or desirability, of this alternative.

Of note in Table 10-6 is that the performance of the Black Brook-Venus 345 kV line is inferior in some respects to that of the Black Brook-Venus 115 kV line. Both of these alternatives would be operated at 115 kV in the near term, so the difference in performance for these alternatives is minor. Differences in line construction and connections account for the difference reflected in the table.

The significance of these electricity demand figures is clearest in light of projected demand growth in the Upper West area. Present-day 1998 peak demand in this area is about 210 MW. WPSC expects this to grow to about 265 MW by 2010.

Costs

The next several columns of Table 10-6 list the rate impacts of several cost components for each alternative. The column labeled "Construction" includes all construction work identified in the earlier project descriptions. This includes new facilities, upgrades of existing facilities and temporary facilities needed to support the system during the construction process.

The "Other Facilities" column in Table 10-6 accounts for the impact of each alternative on the need for other system reinforcements. This is largely a consequence of the configuration of each alternative. In essence, the D-SMES plan, Parallel Circuit plan and two Black Brook-Venus plans serve to facilitate the transfer of power from the Wausau area into the Upper West area. In contrast, the proposed Tripoli-Rhinelander line and the Prentice-Rhinelander plan provide an entirely new link from the new 345 kV line to Rhinelander's Highway 8 Substation. As a consequence, these latter two plans do not require some facilities that are required by all other plans.

As discussed previously, the Tripoli-Rhinelander line would require that the 345 kV Arrowhead-Weston line be built along the northern corridor between Exeland and Weston. None of the alternative plans has this restriction. The added economic impact of building the 345 kV line along the northern (Tripoli) corridor rather than the southern (Owen) corridor is included under "345 kV Routing" in Table 10-6.

Finally, each plan has an effect on the electrical losses that occur on the system. Loss reduction is valuable in that it reduces the need to purchase electricity or power plant fuel. It also reduces the need to build generation or arrange to purchase generation capacity from others. Accordingly, loss reduction can be readily expressed in economic terms. The column labeled "Loss Credit" reflects this effect.

The final column reports the total economic impact of the alternatives, obtained by summing these four cost components.

Other characteristics of alternatives

Some additional distinctions between plans are worth noting. The Tripoli-Rhinelander plan requires that the Arrowhead-Weston 345 kV line be built. A Prentice-Rhinelander line could be connected without building a new 345 kV line. However, this would place a significant strain on the existing system west of Prentice, making the need for significant reinforcement of that system more pressing than it is today. The performance results in Table 10-6 assumed that a Prentice-Rhinelander line would include a connection to the Arrowhead-Weston 345 kV line.[262] The other four alternatives would be much less dependent, in terms of their effectiveness in solving Upper West area problems, on the construction of the Arrowhead-Weston 345 kV line.

The Tripoli-Rhinelander plan, as proposed, would not provide any support to the area encompassing Ladysmith and Park Falls. Previous transmission studies, including AP-8, have identified the need for some support to this area in the future. The Tripoli-Rhinelander plan could be reconfigured to provide such support, either through construction of a 115 kV transmission line between Tripoli and Prentice, or installation of an additional substation on the Arrowhead-Weston line. Using the applicants' cost assumptions, these projects would cost roughly $2.5 million and $4 million, respectively.

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[262] The environmental analysis in this document does not include review of a connection to the proposed 345 kV line. A connection would add between 200 feet and 12 miles to the length of the Prentice-Highway system alternative.

In contrast, the Prentice-Rhinelander project provides a connection to the Osprey substation, thereby supporting both the Ladysmith-Park Falls area and the WPSC Upper West area. One problem with this configuration, however, is that the existing 115 kV system west of Prentice would be relied upon to carry a significant amount of power between the 345 kV line and the new Prentice-Rhinelander 115 kV line. Much of this system was built only to serve the relatively modest local electrical demand. As a result, under moderate-to-high levels of power transfer from the west, the outage of the Ladysmith-Weston portion of the 345 kV line would cause the existing Osprey-Prentice line to overload. This would require that the Prentice-Rhinelander line be disconnected almost any time that the Ladysmith-Weston line were forced out of service.

Alternatively, this Osprey-Prentice line could be rebuilt with larger conductors. The applicants estimate this work at $8.5 million (the line is actually owned by another utility, NSPW, which would presumably be the party to carry out such a project). Assuming that large, low-resistance conductors comparable to those proposed for the Tripoli-Rhinelander line were used in any such rebuild, a significant part of this cost would be offset by credits associated with decreases in losses.

Environmental Analysis of Transmission System Alternatives

As a particular geographic area experiences economic growth, demand for increased electrical capacity must be met. Need for additional electrical support to an area is analyzed by a detailed engineering study. The study looks at the regional electrical problems in an area and considers a number of solutions. Several reasonably effective solutions may be identified. After the list of candidate solutions has been identified, an environmental review is conducted to evaluate the relative environmental performance of each candidate solution.

This section describes the environmental analysis of the possible transmission solutions that could bring additional electrical support to the Rhinelander area. First, the methods used to conduct an environmental system level review are described. Then, the results of the analysis are presented. This section concludes with a brief summary of the findings of the environmental system level review.

Methods

The methods used to conduct a system level environmental analysis are different than those used to analyze a specific transmission line route. When a specific transmission line route is analyzed, the analysis focuses on a set of selected alternate transmission line routes that have a specific centerline and ROW width. The environmental analysis consists of assessing the nature and degree of impact that would potentially be caused by the construction, operation and maintenance of the proposed line.

When conducting an environmental analysis at the system level, a number of solutions to an electrical system problem are evaluated. System options may include both transmission and non-transmission solutions. The system level environmental analysis aims to identify the relative risk of potential impacts of various options and provide this information for use in selecting the ideal solution to the electrical problem.

A study area approach is used for analyzing transmission line system options. For each system option, a study area is defined by establishing a representative centerline or location for the transmission line. An effort is made to select a reasonable location for this centerline. After the centerline is chosen, a study area is established that extends a specified distance from either side of the centerline for its entire length. The width of a study area is a matter of judgment. It needs to be wide enough to encompass most reasonable variations in the location of the line, but narrow enough to facilitate analysis. If a study area is too large it becomes very difficult to analyze and regional differences between study areas may be blurred or lost.

Because this kind of review relies on analysis of a study area rather than a narrow ROW affected by a particular line, the environmental review cannot determine the exact magnitude of environmental impact for each option. Instead the analysis focuses on the relative risk of environmental impact associated with construction and operation of each system option. This is accomplished by selecting factors that can be used to measure the quality of the natural environment within each option study area.

System options

Four system options were evaluated as possible alternative solutions to the proposed Tripoli-Rhinelander transmission line. (A Black Brook to Venus transmission line comprises two of the system options, at two different voltages.) These system options are listed below in Table 10-7. For a more detailed description of these options, please refer to the engineering analysis of these options found earlier in this chapter.[263]

[263] No environmental analysis was done for the D-SMES option since it would not include installation of any new permanent transmission lines and the units would be placed on existing substation sites.

Table 10-7 Tripoli-Rhinelander system options

Name	Description
Black Brook-Venus 115 kV or 345 kV Plan	Construct a new 115 kV or 345 kV line between the Black Brook and Venus Substations. Rebuild the existing Bunker Hill Switching Station to Black Brook 115 kV line. Expand the Black Brook Switching Station.
Parallel Circuit Plan	Construct two parallel 115 kV single circuit, single pole lines replacing the existing 115 kV single circuit H-frame line from Skanawan Switching Station to the Highway 8 Substation. Replace the existing 115 kV line between the Black Brook Switching Station and the Aurora Street Substation with two parallel 115 kV circuits.
Prentice–Rhinelander	Construct a 115 kV single circuit, single pole line between Prentice Substation in Prentice and the Highway 8 Substation in Rhinelander.

Environmental review of system options

Three of the four system options involve more than one study area. Maps showing each of the system options are in Vol. 2, Figures 2-32 through 2-34. Environmental data was reviewed for each individual study area and these data were then summed to provide system alternative information.

A representative centerline in each study area was chosen and a study area was defined that encompasses the landscape within 1.25 miles on either side of the assumed centerline.[264] Several environmental factors were analyzed within each study area to determine the relative environmental risk of building the proposed lines in each area. The following is a list of the factors used in the analysis:

- Land cover.
- Corridor sharing opportunities.
- Public lands.
- Water body crossings.
- Urban centers.

Because a system level analysis generally covers a large geographic region, it is most effectively accomplished with the aid of a GIS. Use of GIS data allows analysis of the relative abundance

[264] A 2.5-mile wide study area was developed for each discrete piece of the system options, e.g. the Parallel Circuit Plan includes a Skanawan to Highway 8 study area and a Black Brook to Aurora Street study area. The data for the study areas comprising a system option have been summed to assess the relative risk of environmental impact for each system option and provide a comparative review among options.

of land cover and land use types within each study area to provide a quantitative analysis of the landscape.

Land cover

Each system option and variation was analyzed using GIS data to determine the proportion of land cover types found within each 2.5 mile-wide study area. The following land cover classes were identified: urban (city or village), barren land (less than 30 percent vegetative cover, sand, bare soil, exposed rock), grassland (non-cultivated herbaceous vegetation dominated by grasses; this includes pasture, restored prairie, lands in the CRP, and idle farmland), forest (upland broadleaved deciduous and coniferous forest), open water, wetland (including forested wetlands), shrub land, and agriculture (row, forage, cranberry bogs).

The results of this land cover analysis are shown below in Table 10-8. The percentages of shrub land, open water, barren land, and grassland have been grouped into a category called "Other."

Table 10-8 Land cover analysis—Tripoli-Rhinelander system alternatives

System Option Study Area	Length (miles)	Area (acres)	Public Lands (%)	Forest (%)	Wetlands (%)	Agriculture (%)	Urban (%)	Other (%)
Black Brook-Venus	45.4	74,720	2.4	40.4	24.2	15.3	3.3	14.6
Parallel Circuit Plan	24.5	40,184	0.8	42.8	20.4	12.4	3.6	20.4
Prentice-Rhinelander	47.7	76,829	1.9	16.0	22.9	1.3	1.2	58.4*

Note: Some of the system options include more than one study area.

* The study area selected for the Prentice-Rhinelander system option follows USH 8 all the way from Prentice to Rhinelander. USH 8 passes through an area near USH 51 and the city of Rhinelander that is abundant in lakes. The 2.5-mile wide study area encompasses several of these lakes in their entirety and portions of many others. Approximately 53 percent of the area within the "Other" category is open water.

General information for each system option

Table 10-9 Black Brook-Venus 115 kV or 345 kV

Environmental Factor	Includes Black Brook-Venus (Black Brook-Aurora to Venus) and Black Brook-Bunker Hill
Length (miles)	45.4
Predominant land cover	Woodland
Corridor sharing opportunities	Existing transmission 100 percent of route and parts of Highway 64 and Highway 45/47
Urban centers	Antigo
Water body crossings	East Branch Eau Claire River, several small lakes, Hunting River, Pelican Lake
Public lands	Ackley Wildlife Area, statewide spring ponds, Upper Wolf River Fishery Area, statewide habitat areas

Discussion: This system option was examined as three primary study areas, Bunker Hill-Black Brook, Black Brook-Aurora Street, and Aurora Street-Venus. The centerline of the study areas follows an existing transmission line from Bunker Hill Switching Station to Black Brook Substation and proceeds due east from Black Brook Substation into the city of Antigo (to the Aurora Street Substation) and then north along the existing transmission line ROW to the Venus Substation.

The dominant land cover for this system option is woodland, and to a slightly lesser extent wetland, although agriculture comprises nearly one-third of the land area in the Black Brook-Aurora Street study area. Presumably the existing transmission line corridor between Bunker Hill Substation and Black Brook Substation and between Black Brook Substation and Venus Substation has been maintained clear of tall-growing vegetation. Little or no additional clearing of woodland would be needed to accommodate the rebuild of the Bunker Hill-Black Brook 115 kV line or the additional 115 or 345 kV transmission line between Black Brook-Venus.

Table 10-10 Parallel Circuit Plan

Environmental Factor	Includes Skanawan to Highway 8 and Black Brook to Aurora Street
Length (miles)	24.5
Predominant land cover	Woodland, agricultural
Corridor sharing opportunities	Existing electric transmission line 100 percent of route, also partially on Highway 64
Urban centers	S. Rhinelander, Antigo
Water body crossings	Wisconsin River, west and east branches of the Eau Claire River, several creeks, Antigo Lake
Public lands	Lincoln County Forest, Langlade County Forest, Stevens Point Foundation "Treehaven" property
Notable features	Drott Landing Field, Rhinelander-Oneida County Airport

Discussion: The parallel circuit plan would utilize existing transmission line corridors to construct two new 115 kV single pole lines between Skanawan and the Highway 8 Substation and two new 115 kV single pole lines between Black Brook and the Aurora Street Substation. Each pair of lines would occupy an ROW that would be 120 feet wide. The new lines would replace the 115 kV line on H-frame structures that currently exist within each study area. The centerline of the 115 kV lines was used as the representative centerline for each study area. The existing Skanawan-Highway 8 line passes through the University of Wisconsin-Stevens Point Treehaven property. This land is a dedicated environmental education center and is used extensively by the university for research and education purposes. The corridor has been maintained as a cleared ROW and it may be possible to construct the replacement lines with minimal ROW expansion. Short-term impacts caused by construction, however, would still occur and could affect sensitive resources throughout the study area. The Black Brook-Aurora Street portion of this system option would be built in a similar fashion—replacing H-frame structures with two lines on single pole structures. Concerns regarding visual-aesthetic impacts are likely, given the more urban location of the Aurora Street Substation. There are high quality aquatic resources within both study areas. It may be possible to avoid impacts to these resources with sensitive routing of a transmission line.

Table 10-11 Prentice-Rhinelander

Environmental Factor	Prentice–Rhinelander (Centerline at Highway 8)
Length (miles)	47.7
Predominant land cover	Open water and wetland
Corridor sharing opportunities	Highway 8-100 percent of route and also partially on Wisconsin Central Railroad
Urban centers	Tomahawk, Prentice, Rhinelander
Water body crossings	Somo River, Big Somo River, Tomahawk River, Lake Nokomis, Deer Lake, Wisconsin River
Public lands	Jennie Creek Fishery Area, Wayside Parks
Notable features	Lake Nokomis chain of lakes and surrounding recreational areas, Rhinelander-Oneida County Airport

Discussion: Please refer to the Tripoli-Rhinelander Environmental Analysis in Chapter 11 for a more detailed discussion of features, potential impacts, and routing possibilities in this study area.

Environmental comparisons for the system options

Corridor sharing opportunities

Existing infrastructure is an important component of system level analysis because it may influence the quality of the resources present and because of the opportunities it provides for corridor sharing. Corridor sharing can present an opportunity to reduce impacts on natural resources. In many of its previous decisions, the Commission has supported corridor sharing as an acceptable method for reducing a project's environmental cost. For example, if a transmission line can be constructed along a roadway, it may be possible to use road ROW for supporting heavy construction equipment, reducing the need to drive the equipment across sensitive natural resources. However, a transmission line located near a roadway is more visible to users of the road, including individuals who have homes located on the road. All of the proposed system options have substantial opportunities to route a transmission line within or adjacent to an existing infrastructure corridor.

Water body crossings

When examining a study area, it is important to be aware of aquatic resources such as wild and scenic rivers, concentrations of lakes, or large expanses of wetlands. Although all three system options appear to have approximately the same percentage of land cover consisting of wetlands, the Prentice-Rhinelander option has the most open water (Prentice-Rhinelander has 53 percent, Black Brook-Venus has 2 percent, and the Parallel Circuit Plan has 3 percent) within the defined study areas due to the selection of a centerline using USH 8.

The NRI is a register of river segments that meet certain qualifications for being named as national wild, scenic or recreational river areas. To be listed, river segments must meet three basic criteria:

- Be free-flowing and 25 miles or longer.
- Have a relatively undeveloped river and river corridor.
- Possess outstanding natural and/or cultural values.

There are two NRI listed rivers, the Wisconsin River and the Somo River, within the study areas that are part of this system level review. Both lie within the Prentice-Rhinelander study area. The Wisconsin River is within the Skanawan to Highway 8 study area that is part of the Parallel Circuit option.

Public lands

Public lands and their relationship to utility infrastructure may be viewed differently by different segments of the population. Some public lands are set aside for purposes of recreation and an escape from an urban setting, or to protect habitat for declining species. When public lands are viewed in this manner, the presence of an electric transmission line or any other human-made facility may be seen as an intrusion and an incompatible use of the area. Others may think that public lands provide opportunities for siting electric transmission line facilities that avoid private property and many of the potential human impacts associated with these lines. The potential for significant environmental impacts on biological resources is often greater on public lands and the use of these areas would require special permission and easements from agencies and governmental bodies that own the land. Condemnation authority given to public utilities for siting new facilities cannot be exercised on publicly owned property.

All of the study areas contain at least one area of public lands. An existing transmission line corridor passes through the Ackley Wildlife Area in the Bunker Hill-Black Brook study area, which is part of the Black Brook-Venus option. An existing transmission line also passes through the University of Wisconsin-Stevens Point Treehaven property in of the Parallel Circuit Plan study areas. This property is heavily used by the public for environmental and educational purposes. The Prentice-Rhinelander study area encompasses the Jennie Creek Fishery Area and some wayside parks.

Urban centers

Urban centers are also important factors in a system level review. In some cases, urban centers may provide increased opportunities for corridor sharing. In addition, some urban centers and associated land uses lend themselves to the presence of an overhead electric transmission line. For example, industrial parks and business parks may provide a compatible landscape for a transmission line and routing a transmission line through or close to an urban center can reduce impacts to natural resources in the surrounding countryside. However, because urban centers and their surrounding suburban developments are more densely populated, aesthetic issues and other concerns, such as exposures to magnetic fields, are often raised when siting a transmission line near where people live, work, or attend school. Also, there may be homes or other buildings that result in electrical code clearance problems.

Tomahawk, Rhinelander, Antigo, and Prentice are the urban areas identified in the examined study areas. All of the study areas encompass at least one urban center.

Summary of environmental considerations for the transmission system alternatives

The three transmission system options to the proposed Tripoli-Rhinelander transmission line vary greatly in length and in their potential to result in adverse environmental effects. Two of the options, the Black Brook-Venus option and the Parallel Circuit Plan, contain existing transmission line corridors that could be used to site and construct the new transmission lines. The Prentice-Rhinelander option and WPSC's preferred transmission solution, a Tripoli-Rhinelander line, would require creating a new transmission line corridor, using existing road and railroad ROWs where possible and practical. Although the Prentice-Rhinelander study area contains the most open water, it may be possible to avoid affecting high quality aquatic resources with sensitive routing. A slight adjustment in the study area could allow additional corridor sharing with the Wisconsin Central Railroad and an existing transmission line.

The length of new construction required is the shortest for the Parallel Circuit Plan (24.5 miles) and the longest for the Prentice-Rhinelander option (47.7 miles). The proposed Tripoli-Rhinelander line is approximately 37 miles long.

From an environmental perspective, it appears that the Parallel Circuit Plan option has several advantages over the other transmission system alternatives. However, other factors, including cost, electrical performance, and other system benefits must be considered in addition to environmental issues in determining the best solution for meeting the growing energy demand in the Rhinelander area.